(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
23 September 2004 (23.09.2004)

PCT

(10) International Publication Number
WO 2004/080790 A2

(51) International Patent Classification[7]: B63B

(21) International Application Number: PCT/US2004/006944

(22) International Filing Date: 5 March 2004 (05.03.2004)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
60/453,094 6 March 2003 (06.03.2003) US
60/507,174 30 September 2003 (30.09.2003) US

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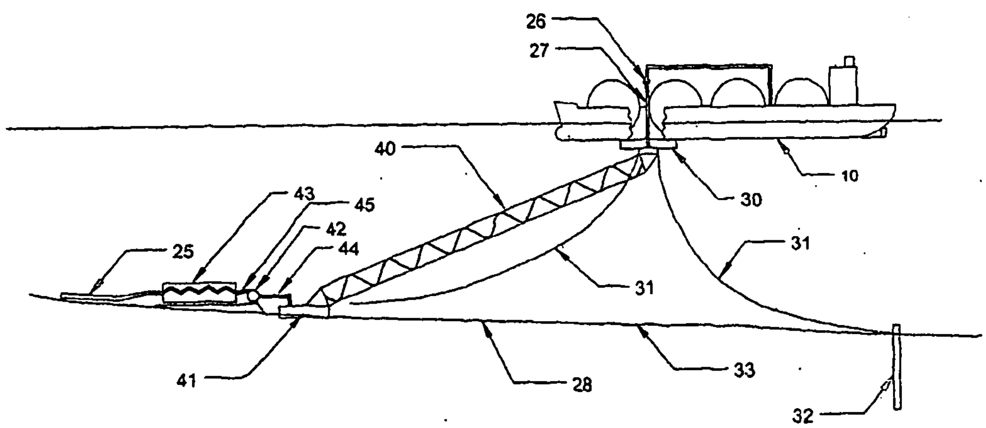
(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BW, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NA, NI, NO, NZ, OM, PG, PH, PL, PT, RO, RU, SC, SD, SE, SG, SK, SL, SY, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, YU, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HU, IE, IT, LU, MC, NL, PL, PT, RO, SE, SI, SK, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:
— *without international search report and to be republished upon receipt of that report*

For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

(54) Title: DISCHARGE OF LIQUIFIED NATURAL GAS AT OFFSHORE MOORING FACILITIES



(57) Abstract: A method and arrangement for transferring liquified natural gas from a seagoing tanker to an on-shore facility including boosting the pressure of the liquefied natural gas to above the critical pressure and passing the liquefied natural gas through a heat exchanger immersed into the sea thereby heating the gas to near ambient temperature.

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DISCHARGE OF LIQUIFIED NATURAL GAS AT OFFSHORE MOORING FACILITIES

RELATED APPLICATION

This application claims priority of United States Provisional Patent Application No. 60/453,094, filed March 6, 2003 and United States Provisional Patent Application No. 60/507,174, filed September 30, 2003, both of which are incorporated herein by reference.

FIELD OF THE INVENTION

This invention relates to the field of transport of cryogenic fluids by ships and more particularly to the field of the transfer of cryogenic fluids from a floating vessel into a pipeline submerged in the sea.

BACKGROUND INFORMATION

Liquified Natural Gas (LNG) is a hydrocarbon mixture comprised primarily of methane, but may also contain some lower hydrocarbons typically c2 through c4. This liquid, in the existing technology, is transported at sea by special tanker vessels at near atmospheric pressure and a temperature of approximately -161 degrees C.

These tanker vessels typically discharge their cargo at in-harbor ordinary piers into storage tanks. The gas is then typically dispatched from the storage tanks via pipeline to consumers at ambient temperature and moderately high pressure. The distribution pipeline pressure is usually in the range of 5 MPa to 12 MPa. Before being dispatched, the gas must be heated.

The heating is ordinarily done in heat exchangers using sea water if this is available at a suitable temperature or by using some of the gas to heat the fluid used in the heat exchangers. If the latter method is the only method used to heat the gas, then the consumption of gas for this purpose is ordinarily around 1.25% of the throughput.

Taking a throughput of 20,000 tonnes/day and assuming that the value of the delivered gas is US$200 per tonne, this method of heating the gas consumes 250 tonnes gas per day at a cost of US$50,000 per day.

To heat the LNG from -161 degrees C to ambient at the pipeline pressure requires about 600 kJ/kg of gas. It can be assumed that seawater is used for heating the gas. This water may be cooled in the equipment to no less than 2 degrees C. The heat capacity of water is approximately 4 Kj/kg/deg C. Taking an inlet water temperature of 8 degrees C, then each kg of water may deliver (8-2)*4=24 kJ of heating. Thus in this example, 600/24=25 kg of water is required to heat one kg of LNG. In the example of delivering 20,000 tonnes LNG per day 500,000 tonnes/day of seawater is required for purposes of heating the LNG. This requires a supply of approximately 6 m^3/second. This is a major quantity which would typically require large intake works and discharge works.

Note, that if the sea water temperature is to be lower at some part of the year, for example 4 degrees C, the amount of water required would be 3 times as large or 18 m^3/second. The capital and operating costs of a system heated by sea water depend strongly on local conditions and could exceed, by a considerable margin, the corresponding costs of using the gas itself to provide the energy for heating.

An alternative method for discharging gas from a cryogenic tanker consists of using equipment aboard the tanker to raise the pressure of the liquid to the pressure of the subsea pipeline and then heat the gas to a temperature of at least -40 deg C or more typically to a range between -10 deg C and 0 deg C. In this case the tanker may in some cases be able to deliver the gas to an existing infrastructure of submarine gas pipelines, such as for example exists in the Gulf of Mexico or the North Sea.

In the alternative method, the cryogenic tanker acts as the storage in the system and delivers gas as demanded at any one time.

Each tanker must in the alternative method have the equipment to raise the pressure of

the liquid to pipeline pressure and the equipment to heat the gas to near ambient temperature. A typical discharge rate is 0.5 m^3/sec of LNG and a typical pipeline pressure is 10 MPa. The theoretical pumping power is thus 5 MW. Allowing for all losses, a practical power supply would need a capacity of around 7 MW. Thus each tanker must be equipped with a pumping plant with a power on the order of 5 to 10 MW. Consequently it is very costly to equip each vessel with this capability.

The alternative method is particularly suited for use with single point moorings such as for example featured in United States Patents 5,305,703 and 5,380,229. This method also alleviates present concerns about the security and danger of fires and explosions originating from a burning and disintegrating cryogenic tanker, because the discharge facilities may be placed far from the shore distant from population centers.

The present invention is directed to the alternative method of discharging cryogenic fluids such as LNG into subsea pipelines for delivery to a pipeline network operated at near ambient temperature.

Very large cost savings are achieved by not equipping the tankers with the high pressure pumps and the heating equipment for heating the cryogenic fluid to near ambient temperature. This invention teaches the placement of this equipment on the seabed and to use the ambient heat capacity of the seawater to heat the cryogenic fluid.

SUMMARY OF THE INVENTION

The present invention relates to the discharge of LNG at relatively low pressure within the typical capability of currently existing cryogenic tankers into a subsea system for direct delivery at near ambient temperature to a gas pipeline system operated at normal operating pressures.

The normal operating pressures of the gas pipelines may be in the range of 5 to 20 MPa.

The discharge pressure of the cryogenic tanker may be in the range of 0.5 to 1 MPa. Pumps provided at the discharge point on the seabed or at a nearby platform remote from the tanker boost the pressure of the LNG to the pipeline pressure. These pumps feed the LNG into a subsea heat exchanger of special design that interacts directly with the ocean and thereby efficiently and inexpensively heats the LNG to near ambient temperature.

The LNG may be maintained at all times above the critical pressure during the heating process such that it is converted to pressurized gas at near ambient temperature without changing into two phases at any time during the heating process.

BRIEF DESCRIPTION OF THE DRAWINGS

Figure 1 is a schematic view of an existing technology arrangement of discharging LNG from tanker vessels into pipeline systems carrying pressurized gas at near ambient temperature.

Figure 2 is a schematic view of another existing technology arrangement for discharging LNG from tanker vessels into pipeline systems carrying pressurized gas at near ambient temperature.

Figure 3 is a schematic view of a first embodiment, in accordance with the present invention, for discharging LNG from tanker vessels into pipeline systems carrying pressurized gas at near ambient temperature.

Figure 4 is a detailed view of an arrangement of a pumping plant boosting the LNG pressure to the pipeline pressure of Figure 3.

Figure 5 is a plan view the heating plant heating the LNG to near ambient temperature.

Figure 6 is a cross sectional view of the heat exchanger shown in plan view on figure

5.

Figure 7 is an alternative arrangement in plan view of the heating plant of figure 3.

Figure 8 is a plan view of a second embodiment for discharging liquified natural gas.

Figure 9 is a plan view of a third embodiment of the invention.

Figure 10 is a side view of figure 9.

Figure 11 is an oblique view of a partially cut away perpendicular projection of a third embodiment of the invention.

Figure 12 is a detailed view of the arrangement of a pumping plant boosting the LNG pressure to the pipeline pressure that is particularly suitable for use in connection with a third embodiment of the invention.

Figure 13 is a detailed oblique perpendicular projection of a small cut away of the heat exchanger in a third embodiment of the invention focusing on an arrangement for anchoring the heat exchanger pipes.

Figure 14 is a detailed oblique perpendicular projection of a small cut away of the heat exchanger in a third embodiment of the invention focusing on an anchoring arrangement for the heat exchanger pipes.

Figure 15 is a view of vortex suppression and heat transfer fins applicable to a first and third embodiment of the invention.

DETAILED DESCRIPTION

Figure 1 illustrates one example of conventional liquid transfer technology. Figure 1 illustrates the most common plant for transferring LNG from a LNG tanker vessel to overland pipelines. An LNG tanker 10 is shown moored to a number of dolphins 12

using mooring lines 11 that maintain the tanker 10 in a nearly fixed position relative to a loading platform 13. The loading platform 13 is connected by cryogenic piping 15 to a cryogenic storage 20 on land. The shoreline 18 separates the land and the sea. When transferring the cryogenic liquid from the tanker's 10 piping, a flexible pipe 14 connects the tanker's 10 piping to the receiving pipeline 15. The flexible pipe 14 ordinarily comprises a series of articulated loading arms in parallel.

The cryogenic fluid that is discharged from tanker 10 is stored in tank 20. The cryogenic fluid is delivered from tank 20 to the customer delivery gas pipeline 25 via suction pipe 21, booster pump 22, pipe 23, and heater 24. The gas leaving heater 24 would be delivered at the back pressure of pipeline 25, typically 5 to 12 MPa and at a temperature near ambient, typically -10 to 0 deg C. A main advantage of the system illustrated by figure 1 is that there is no direct connection between the tanker 10 and the customer delivery pipeline 25, enabling flexible scheduling of tankers 10 thereby reducing the operating costs of tankers 10. Storage 20 is used as a buffer in the system, however, the storage 20 entails high capital costs and the storage 20 is often perceived as a danger to the surrounding community because a fire or spill at tank 20 may not be controllable and may result in a very large fire or in some scenarios a major explosion. In some communities, it is difficult to site the unloading facilities 12 and 13 and the storage facilities 20 on account of these dangers.

Figure 2 illustrates another conventional technology which may remove the tanker 10 far from land when discharging its cargo and in effect uses tanker 10 for storage in lieu of the storage 20 in Figure 1. Tanker 10 is shown moored to a submerged mooring of the type described in US Patents 5,305,703 and 5,380,229, however, other submerged moorings may also be used, indeed virtually all existing offshore moorings of the single point mooring type or the multi buoy mooring type may be used.

The application of any specific mooring may be determined by capital and operating costs at the specific site. Regardless of the type of mooring used, the function is the same. In this case the pumps 22 pressurizing the discharged fluid and the heater 24 are located on the tanker 10. For the sake of clarity the pumps 22 are shown on top of the

cargo tanks, although the pumps may be located within the hull of vessel 10 or on deck. The LNG is sent through a booster pump 22 boosting the pressure of the LNG to a pressure above the pressure in the delivery pipeline 25. The pump 22 delivers the LNG to the heater 24 where the gas is heated to near ambient temperature.

Figure 2 illustrates the vessel 10 moored to a single point mooring 30. The single point mooring 30 is moored to the seabed through anchor chains 31 and anchors 32. The gas is thereby conveyed through a fluid swivel 26 and connecting pipe 27 through a flexible riser 29 to a pipeline end manifold 28 on the seabed. The riser 29 is in fluid connection to the delivery pipeline 25 at the pipeline end manifold 28, enabling continuous delivery of gas whenever a vessel 10 is moored at the mooring 30.

Figure 3 schematically illustrates a first embodiment of the invention for discharging liquified natural gas from tanker vessels into pipeline systems carrying pressurized gas at near ambient temperature. A cryogenic tanker 10 delivers LNG to a sub-sea delivery pipeline 25 in a manner similar to the conventional technology systems shown in figure 2. In this first embodiment of the invention, the tanker 10 delivers the LNG at the standard pressure of 500 - 1000 kPa to a sub-sea booster pump 42, which boosts the fluid pressure to above that of the delivery pipeline 25. The cryogenic fluid leaving pump 42 is then passed through heater 43 which raises the temperature of the gas to near ambient. Heater 43 is of special design as detailed in this specification and illustrated in figures 5, 6 and 7.

Figure 3 illustrates the vessel 10 moored to a single point mooring 30. The LNG is therefore conveyed through a fluid swivel 26 and connecting pipe 27 through a flexible riser 40 to a pipeline end manifold 41 on the seabed. The riser 40 may for example be constructed as taught by United States Patent 5,553,976. The riser 40 is in fluid connection with pump 42 at the pipeline end manifold 41, enabling continuous delivery of gas whenever a vessel 10 is moored at the mooring 30. The fluid connection between the pipeline end manifold and pump 42 comprises suction pipe 44, a check valve preventing back flow, and possibly other valves required for the safe operation of the system. Pump 42 is in fluid connection with heater 43 through

discharge pipe 45.

A special problem may exist at the time of start up of the process. LNG ordinarily has a boiling temperature of -161 deg C at atmospheric pressure. At 500 kPa the boiling temperature is approximately -140 deg C. It may be anticipated that the riser 40 is at ambient temperature before commencing delivery of LNG to pump 42 on the seabed. Prior to start-up of the pumping, riser 40 may contain natural gas under pressure. The first step in the start-up is to bleed off the pressure in riser 40 through back flow in pipe 27 to a vent on vessel 10. The riser 40 is now filled with ambient temperature gas at near atmospheric pressure. The riser 42 may, for example, be a metal pipe with a diameter of 500 mm. The gas at atmospheric pressure and ambient temperature has an approximate weight of 0.8 kg/m^3. The pipe between the delivery pump in vessel 10 and the booster pump 42 may comprise a lineal length of 300 m. Thus the volumetric capacity of the pipe is n/4*.5^2*300 = 120 m^3, thus containing approximately 0.8*120 = 100 kg of gas in vapor form. The heat of vaporization of LNG is approximately 550 kJ/kg and c_p is approximately 3 kJ/kg. Assuming a cool down of approximately 175 degrees and liquefaction the energy required is 550 + 3*175 = 1075 kJ/kg or 108,000 kJ for the 100 kg vapor content of the riser 42. The specific heat of the LNG is approximately 3 kJ/kg/deg C. Assume that the LNG is heated 10 deg C then 108,000/10/3 =3600 kg is required to entrain the content of riser 40 into the LNG. The density of the LNG is approximately 400 kg/m^3. Consequently 3600/400 = 9 m^3 of LNG being heated 10 degrees is needed to entrain the gas in riser 40 into the LNG. The cross sectional area of the pipe in riser 40 in this example is approximately 0.19 m^2. Therefore the content of approximately 9/0.19 = 50 m of pipe is needed to provide the energy for entrainment of the gas in the riser 40 into the initial delivery of LNG to pump 42. This is unlikely to work because the heat cannot be evenly distributed in the initial slug of LNG. If it does work it would subject pump 42 to thermal shock and to extreme pressure fluctuations on the suction side during start-up.

An alternative arrangement for starting the delivery of LNG from vessel 10 to the delivery pipeline 25 may be to equip riser 40 with two parallel fluid paths and manifold these fluid paths into the piping of vessel 10 such that during startup LNG

can be circulated by vessel 10 through the two fluid paths in riser 40. This would solve the problem of extreme pressure transients being experienced in the suction 44 of pump 42 during startup, however, the pump 42 would still experience thermal shock being cooled from ambient to approximately - 160 deg C during each start-up. Conventional pumps would need frequent replacement and would be unreliable if subjected to the service conditions described above.

Figure 4 illustrates in more detail the arrangement of pump 42 such that it can reliably start and stop without being subjected to extreme temperature and pressure fluctuations.

Pump 42 is contained within a cryogenic insulated pressure vessel 50. Pump 42 is not connected directly to suction pipe 44 but rather takes suction at 56 through suction pipe 51 within the cryogenic pressure vessel 50. Suction 51 is placed at a low point in cryogenic vessel 50. During normal operations of discharging the ship 10, the cryogenic vessel 50 may be completely filled with liquid, because the capacity of the pumps aboard the vessel 10 may exceed the combined capacities of pumps 42 and 55 removing fluids from cryogenic vessel 50. In addition, the vapor pressure of the LNG transferred may be only slightly above atmospheric about 110 kPa absolute and the discharge pressure of the pumps aboard ship 10 may be on the order of 500 kPa to 1000 kPa. Cryogenic vessel 50 may be located on the seabed as shown in Figure 3 thereby further increasing the pressure at suction 56. However, the cryogenic vessel 50 may be located on a nearby platform above the water.

Cryogenic vessel 50 is also fitted with a pump 55 taking suction 57 through pipe 58 approximately in the center of cryogenic vessel 50. Pump 55 is of much lower capacity than pump 42, however it is of a type that can pump both liquid phase and vapor phases of the contents of cryogenic vessel 50 and deliver these to the discharge pipe 45. This pump 55 is running whenever the pressure is above 300 kPa or the temperature in cryogenic vessel 50 is above -145 deg C. The starting and stopping is automatically controlled by conventional equipment inside cryogenic vessel 50.

When cargo is discharged from ship 10, pump 55 assists in delivering the cargo to discharge pipe 45. When the pumping from ship 10 stops, the cryogenic vessel 50 and the riser 40 (figure 3) are full of LNG. The heat influx from the environment particularly to the riser 40 would rapidly increase the vapor pressure in the riser 40 and also in the cryogenic vessel 50. Pump 55 is sized to remove sufficient liquids during this phase to control the pressure and to draw down the liquid vapor interface 59 in cryogenic vessel 50.

Suppose the system is designed to deliver 1,000 tonnes per hours of LNG. This corresponds to 1000/0.44= 2300 m^3/H = 0.63 m^3/sec. Suppose the delivery pressure in pipe 45 is 11 Mpa then the theoretical power of pump 52 is 0.63*11 = 7 Mw. To account for all losses this pump is likely to need a driver with a power of 10 Mw. The cryogenic vessel 50 may be cylindrical with an internal diameter of 5 meters and a length of 30 meters. The volume of this tank 50 is 585 m^3. Deducting the volume occupied by the equipment inside the cryogenic tank 50 it may have an effective volume of 550 m^3.

Pump 55 may be designed to deliver 0.01 m^3/sec. This pump would need a driver with about 150 kW power. The volumetric capacity of the riser system is in the prior example 120 m^3. Pump 55 would remove this volume in about 120/0.01 = 12000 sec = 3.33 Hours. In addition pump 55 would remove approximately 50% = 0.5*550 = 275 m^3 of the liquid in cryogenic vessel 50 in an additional time of 275/.01= 27500 seconds = 7.6 hours. Consequently approximately 11 hours after ship 10 stops delivery will pump 55 take suction within the gas filled volume above the interface 59 of cryogenic vessel 50.

Cryogenic tank 50 has an exterior surface of approximately 600 m^2. Suppose that the insulation layer is 100 mm thick and comprised of a material with a heat conductivity of 0.04 w/m/deg C. Thus the heat influx in the tanks is 10*0.04*600 = 240 w/deg C. Assume a temperature differential of 170 deg C then the heat influx into tank 50 is 240*170= 40,000 w or 40 kW. The heat of evaporation of methane is approximately 550 kJ/kg thus 40/550= 0.072 kg/sec evaporates. The density of LNG vapor at -160

deg C and atmospheric pressure is approximately 120 kg/m^3 requiring removal of approximately 0.072/120 = 0.6 liters per second. This is negligible compared to the capacity of pump 55. When the content of cryogenic vessel 50 is reduced to 50% 11 hours following the discharge of ship 10 the cryogenic vessel 50 contains approximately 275*440= 121,000 kg of LNG. The evaporation per hour is 0.072*3600=260 kg/H. To completely evacuate cryogenic vessel 50 due to heat influx from the environment would require 121,000/260 = 465 hours = 19 days.

Cryogenic vessel 50 is fitted with check valves 49 preventing backflow into pipe 44 and check valves 53 preventing backflow from high pressure pipe 45 into the cryogenic vessel 50. Cryogenic vessel 50 would normally also be fitted with a range of items such as, penetrations for electric cables, instrumentation and relief valves, needed for safe operation of the facility.

Start-up is particularly simple and safe with the, arrangement shown in figure 4. The pumps 55 and 42 are always maintained at near the operating temperature of -160 deg C. If an extended period of many days occur between two successive ships 10 then the temperature of pumps 42 and 55 may increase to -145 deg C. At start-up the ship 10 connects to riser 40 and starts pumping. The pumping rate would be on the order of 0.5 m^3/sec. 120/0.5 = 240 seconds later the liquid in riser 40 reaches cryogenic tank 50. The gas at ambient temperature preceding the liquid LNG in riser 40 will be entrained into the liquids of cryogenic tank 50 and increase the temperature of these liquids by less than one deg C. Following arrival of the liquid/gas interface, the liquid level in cryogenic vessel 50 may rise for approximately 9 minutes until the cryogenic tank 50 fills completely, however, prior to this happening, pump 42 may be started. Following the start of pump 42, ship 10 may maintain a pumping rate slightly above the delivery rate to discharge pipe 45 until the cryogenic vessel 50 fills completely. This may be sensed at the ship 10 as a small increase in back pressure. The ship 10 would then normally apply full power to its pumps to increase the pressure in cryogenic vessel 50.

A note is required on the materials used in the pipe of riser 40. This is subjected to

sudden cooling from ambient to -160 deg C at start-up. Completely restrained structures made from metals such as titanium with a low modulus of elasticity and low coefficient of thermal expansion may withstand temperature changes of 180 deg C without becoming over stressed, and may consequently be used for this service. Another candidate material is INVAR which has a very low coefficient of thermal expansion.

Figures 5 and 6 illustrate more detail of heater 43 provided in Figure 3. Figure 5 is a plan view of a number of heat exchanger pipes 60 deployed sufficiently above the seabed such that the ice, which will form on the outside of the pipe does not reach the seabed. Heating of the gas takes place by the seawater flowing naturally around the heat exchanger pipe 60 continuously heating the ice that forms on the outside.

Figure 5 shows in plan view the vessel 10 moored to a single point mooring. The vessel is in fluid connection with a pipeline end manifold 41 on the seabed through flexible riser 40. The pipeline end manifold 41 is in fluid connection with pump 42 that boosts the pressure of the LNG to a pressure above the pressure in the delivery pipeline 25. The pump 42 is manifolded into each individual heat exchanger pipe 60 at manifold 61. The heat exchanger 43 that heats the LNG to near ambient is a series of parallel pipes 60 are deployed in the this case in a circle around the weathervaning circle of ship 10 when ship 10 is moored to the single point mooring. The heat exchanger pipes 60 are manifolded into the delivery pipeline 25 at manifold 62.

Vessel 10 would typically have a length around 300 m. Thus the weathervaning circle of vessel 10 may have a diameter close to 700 m. The parallel pipes 60 in heat exchanger 43 may, for example, be deployed in a circle with a diameter of approximately 1000 m, making each pipe 60 approximately 3000 m long. An approximate calculation of the number of parallel pipes required to heat the LNG e.g. -10 deg C from the inlet temperature of - 161 deg C may be made considering the heat influx into the pipe from the sea water. The prior example of delivering 1000 tonnes/H is used. It is assumed that the seawater surrounding heater 43 has a temperature of 8 deg C. It may be further assumed that the pipe 60 is of nominal

diameter of 250 mm. It will later be shown that the heat influx through the pipe in these circumstances may be on the average 4 kW/m. Thus each pipe can provide 12000 kW of heating. Each kg of LNG requires heating of approximately 600 kJ. The mass flow in each pipe 60 is then 12000/600 = 20 kg/second = 72,000 kg/H. The heating of 1000 tonnes/H thus requires 1000/72 = 14 pipes 60 in parallel. Each pipe is in this example 3000 m long. With the pipe, thus dimensioned, the resulting diameter of the circular heat exchanger 43 approximately 1000 m. As a result, the heat exchanger 43 is placed close to tanker 10 yet at a safe distance such that objects dropped from tanker 10 cannot impact the heat exchanger. Yet the heat exchanger 43 is close to tanker 10 making it a simple matter to maintain a security zone around the mooring and the heat exchanger.

Figure 6 is a detailed view of the arrangement of the heat exchanger pipes 60 above the seabed 33 shown in Figure 5. Figure 6 is a section taken though the heat exchanger 43 shown on Figure 5. The individual heat exchanger pipes 60 are suspended above the sea bed a short distance above the seabed 33, such as, for example 4 meters. The pipes are anchored by anchoring chains 67 to an anchor 65 placed in the seabed 33. A large number of such anchors 65 are placed along the perimeter of heat exchanger 43 such that each pipe 60 is supported properly. To provide additional buoyancy, the pipes 60 may be supported by submerged buoys 69 acting through support chains 68. The pipes 60 may be made of a material that can withstand the cryogenic temperature without becoming brittle. Candidate materials may be stainless steel, aluminum and titanium. For example, if aluminum pipe is used, it may have a coefficient of thermal expansion of 25*10^-6. Assume that the average temperature reduction is 100 deg C then a 1000 m diameter circle would contract 100*1000*25*10^-6 = 2.5 meters. Thus the, lateral movement on each side would be half of this or 1.25 m. Assume that chain 67 is 4 meters long. Following cool down, the pipe would no longer be vertical but tilt approximately 18 degrees from the vertical. A configuration allowing tilt is important because materials which can resist the cryogenic temperature even when restrained such as titanium and INVAR are very costly. Thus, suspending the heat exchanger pipe 60 above the sea bed may help the pipe 60 achieve superior heat transfer conditions and allow for the use of lower cost materials such as aluminum or stainless

steel for pipe 60. The anchoring chains 67 and 68 may also be made of materials resistant to cryogenic temperatures if in direct contact with pipe 60 as shown on figure 6. Alternatively the attachment of chains 67 and 68 may be thermally insulated from pipe 60.

The heat exchanger pipe 60 may be insulated by ice 66 forming on the outside of pipe 60 for almost the entire length between manifolds 61 and 62 shown on figure 5. Although ice is a poor insulator, it will nevertheless limit the effectiveness of the heat exchanger pipe 60. The thermal conductivity of ice increases with reduced temperature. At -140 deg C it is 4.1 W/m/deg C whereas at 0 deg C it is 2.2 W/m/deg C. While heating the gas flowing through heat exchanger pipe 60, the exterior surface of ice 66 is always at 0 deg C. For a given flow velocity of the seawater about pipe 60 and for a given temperature of the seawater, there is an almost constant rate of heat transfer to the ice per unit area of the exterior surface of ice 66. Thus at every point along pipe 60 there is equilibrium between the flow of heat through the ice 66 and flow of heat from the seawater to ice 66.

Seawater flowing past the ice having a temperature of 8 deg C and flowing with a velocity of 0.1 m/sec will transfer 3.7 kW/m^2 through the exterior surface of ice 66. It may be assumed that pipe 60 is filled with LNG at a temperature of -160 deg C. It may further be assumed that pipe 60 is nominally a 250 mm pipe with outside diameter of 273 mm, then ice 66 of a thickness of 106 mm will form limiting the heat transfer to the fluid inside pipe 60 to 5.58 kW/m. It may also be assumed that the prior example of a mass flow of 20 kg/sec and a heat capacity of 4 kJ/kg/deg C, then the increase in temperature in each meter of pipe 60 is 5.58/20/4 = 0.07 deg C. Thus the temperature rises 1 deg C in the interior of pipe 60 as one moves 14 meters downstream near the upstream end. At the downstream end of pipe 60 the content may have reached a temperature of -20 deg C. In this case ice 66 of thickness 9 mm will form. The heat transfer rate is 3.46 kW. The content has a heat capacity of 5 kJ/kg/deg C at this temperature. The increase in temperature per m of pipe 60 is at this end 3.46/20/5 = 0.035 deg C. Thus, at the downstream end, a temperature increase of one deg C may require a length of 29 m of pipe 60 at the conditions cited in the above example in this

paragraph.

The heat exchanger pipes 60 may be deployed in numerous patterns. Assume that the pipes 60 on figure 5 are 4 m apart, then an area of seabed occupied by heater 43 is $3000 * 14 * 4 = 168,000\ m^2$. This corresponds to a square area of 410 m on the side.

Figure 7 shows a possible alternative arrangement of heat exchange pipes 60. Only one pipe 60 is shown distorted within heater area 43 for clarity of illustration. The pipe 60 is suspended in the water column similar to manner shown on figure 6.

Figure 8 illustrates a second embodiment of the invention. In this embodiment, the heat exchanger pipe 80 is buried below the seabed to protect it from fishing gear and anchors. A typical burial depth would be 1 meter. Using typical values for the thermal conductivity of frozen soils the heat influx into a 500 mm pipe may be 1.7 kW/m at the upstream end. Assuming a transfer rate of 1000 tonnes/H which corresponds to 278 kg/sec the total heating requirement is 278 * 600 = 167,000 kW.

Pipe 80 serves in this case the dual role of heat exchanger pipe and delivery pipe to shore. Pipe 80 is shown on figure 8 to cross the shore line 81 and connect to a conventional heater 82. Heater 82 will heat the gas to near ambient and convey the gas to overland delivery pipeline 25. If pipe 80 is 20 km long, then the pipe can deliver 20,000 * 1.7 = 34,000 kW of heating. This is only 20% of the total heating requirement of 168,000 kW, however, taking a throughput of 24,000 tonnes/day and assuming the values cited previously this results in operating cost savings on the order of $10,000 per day. The pipe 80 may be comprised of multiple parallel pipes spaced some distance apart and in this manner obtain the function of the system shown on figure 5 that only uses the ambient heat in the sea water to heat the gas being delivered from the cryogenic tanker 10 to the overland delivery pipeline 25.

In the first embodiment of the invention, vessels trying to anchor above the heat exchanger 43 as shown in Figure 5 may damage or even rupture the pipe with potential catastrophic consequences. Likewise fishing vessels fishing with fishing gear

dragged on or near the seabed may damage the heat exchanger 43 shown in figure 5.

Figure 9 is a plan view of a third embodiment of the invention that avoids the dangers from anchors and fishing gear by protecting the heat exchanger 90 by structures that make the navigation above the heat exchanger by all but very small vessels impossible. In this embodiment, the heat exchanger 90 is contained within a protective structure 91 comprising a series of vertical piles 92 spaced sufficiently close that vessels cannot pass.

In figure 9 the LNG delivery tanker 10 is moored some distance from heat exchanger 90. The LNG is transferred by a riser 40 to sub-sea pipeline end manifold 41, which is in fluid connection with sub-sea pipeline 100. The sub-sea pipeline 100 is in fluid connection with a pumping assembly 96 that is located on a platform 95, which is adjacent to the protective enclosure 91. The sub-sea pipeline 100 need be long enough that a safe distance be provided between tanker 10 and enclosure 90 and at the same time short enough that the enclosed volume of gas can be absorbed by pumping assembly 96. Pumping assembly 96 boosts the pressure of the LNG to a. pressure above the critical pressure and delivers the pressurized LNG trough pipe 97 to heat exchanger 98. Heat exchanger 90 is a long submerged pipe 98 deployed within protective enclosure 91. In Figure 9 pipe 98 is deployed spirally as a clock spring, however many other shapes are possible such as for example vertical axis helix, or other appropriate patterns. Heat exchanger 90 may comprise one single pipe 98, but may comprise numerous parallel pipes 98. Pipes 98 are in fluid connection with delivery pipeline 99, which transports the gas away from the facility to customers.

Figure 10 is a side view of the system shown in Figure 9. It is seen that the vessel 10 floats in the ocean with surface 103. The vessel is in fluid connection with the pipeline end manifold 41 on the seabed 104 through riser 40. Pipe 100 provides a fluid connection between the pipeline end manifold 41 on the seabed 104 and the pumping assembly 96 on platform 95. To comply with present classification rules, the length of pipe 100 may, in most cases, be equal to or more than 3 times the length of tanker 10. Tanker 10 would ordinarily be about 300 m long, thus pipe 100 should be

on the order of 900 meters long. Taking the same practical example used in the explanation for figure 4 pipe 100 would have a nominal diameter of 500 mm and will contain approximately 300 kg of natural gas at atmospheric pressure. The riser 40 may, as in the prior example, have a pipe length of 300 m and the same 500 mm diameter and consequently contain 100 kg of gas at atmospheric pressure.

The entrainment of this gas in the LNG contained within pumping assembly 96 requires cooling at approximately 1075 kJ/kg or 400*1075=430,000 kJ. The LNG contained within pumping assembly 96 has a heat capacity of approximately 3 kJ/kg/deg C. Suppose that the allowable rise in temperature of the LNG contained within pumping assembly 96 is arbitrarily limited to 3 deg C then pumping assembly 96 must contain 430,000/(3*3) = 47,000 kg of LNG at the initiation of pumping by tanker 10. Assuming that the pumping assembly 96 is similar to the vessel 50 in figure 3, then 12 hours following termination of the discharge of vessel 10 it would contain 121,000 kg of LNG. This LNG would evaporate at a rate of approximately 250 kg/H to compensate for transmission of heat through the walls of pumping assembly 96. Thus, as long as the next vessel 10 starts pumping before the evaporation in assembly 96 reduces the content of LNG to 47,000 kg, the system may be safely started. This occurs 296 hours following the departure of the previous vessel 10.

Pumping assembly 96 may be fitted with a refrigeration plant that re-liquefies any evaporated natural gas and returns this liquid to assembly 96. In this event there is no limit to the time between departure of one vessel 10 and the arrival of the next vessel 10. At initial start-up and in the event that insufficient LNG is present in assembly 96 to permit immediate initiation of liquid transfer, cool down will be performed by pumping cold vapor from vessel 10 to pumping assembly 96 through riser 40 and pipe 100. This vapor will be vented at assembly 96. Once a steady state temperature in the system is achieved, final cool down will be performed by slowly adding liquid LNG to the cold vapor being pumped from vessel 10 to pumping assembly 96. Once a small amount of LNG is present in vessel 96 pumping may commence as described above.

Figure 10 further illustrates the discharge pipe 97 from pumping assembly 96 being in

fluid connection with numerous heat exchanger pipes 98. Heat exchanger pipes 98 are usually quite long on the order of several km and terminate at the downstream end of pipe 98 in manifold 102, which in turn is in fluid connection with the delivery pipeline 99.

Figure 11 illustrates in more detail in a partially cut-away oblique perpendicular projection the pumping assembly 96 and the heat exchanger 90. In figure 11 the pumping assembly 96 shown is substantially identical to the assembly 50 illustrated in figure 3.

The pumping assembly 96 delivers LNG to pipe 97 at a pressure that is higher than both the critical pressure of the LNG gas mixture and the pressure in delivery pipeline 99. Pipe 97 is in fluid connection with manifold 105, which in turn is in fluid connection with each of the heat exchanger pipes 98. Manifold 105 may include control valves that permit regulation of the distribution of flow between the heat exchanger pipes 98 and indeed to selectively take heat exchanger pipes 98 out of service by isolating them from manifold 105. Heat exchanger pipes 98 are in figure 11 shown deployed in plane spiral shape. Each pipe 98 is at the upstream end in fluid connection with manifold 105 and at the downstream end in fluid connection with manifold 102. The connection 108 between pipe 98 and manifold 102 is for each pipe 98 shown at the same general elevation at both manifolds 102 and 105. Manifold 102 will normally incorporate control valves throttling the flow in any individual pipe 98 if the temperature of the contained gas is below some set point at the joint 108. The control valves prevent the introduction of gas into manifold 102 and delivery pipeline 99 with a temperature that is too low for the metals used in said pipes 102 and 99.

Pipes 98 are usually of dimensions that they are buoyant in seawater. The pipes 98 are supported within enclosure by an arrangement that permits thermal contraction and expansion and which restrain the pipes 98 sufficiently to resist current, wave, and buoyancy forces and which prevent the pipes 98 impacting each other.

Figure 12 illustrates that when the pumping assembly 96 is placed above water, a

simpler version of the device 50 shown on figure 4 is feasible. The LNG is contained within a spherical tank 114 of conventional design. This tank 114 is supported by a support ring 117 supported on columns 116 on top of platform 95. The LNG is received from the LNG tanker in vessel 114 via pipe 100 and check valve 111. Check valve 111 prevents flow from tank 114 to pipe 100. When no LNG is received via pipe 100 pump 120 is normally stopped. Tank 114 would then contain LNG in the bottom of the tank and gaseous natural gas in the top separated by liquid surface 130. Tank 114 is thermally insulated by insulation 115. The heat influx from the exterior causes a rise in temperature in tank 114. This rise in temperature is canceled by evaporation of the LNG in the tank 114. The resulting gaseous natural gas is vented through inlet 140, valve 141, and flare 142. The vented gas is disposed of in flame 143. The flare 142 is shown immediately adjacent to tank 114 in figure 12. This is feasible, however, flare 142 would normally be placed remote from tank 114 to avoid that the heat of radiation from flame 143 contributes to the heat flux into tank 114.

Valve 141 is remotely operated by conventional systems. When an LNG tanker is present and transfers LNG valve 141 is closed and the liquid surface 130 is at the top if tank 114. In this condition tank 114 would normally be pressurized with a pressure close to the discharge pressure of pumps in the LNG tanker. This pressure would ordinarily be on the order of 300 to 1000 kPa. Pump 120 removes LNG via inlet 121 from tank 114 and discharges into pipe 97 via check valve 123. Figure 12 shows two such check valves 123. Only one check valve 123 is required, however, for reasons of safety several valves 123 in series would normally be employed. Pipe 97 is in fluid connection via the heat exchanger to the delivery pipeline for gaseous natural gas. The discharge pressure of pump 120 is above the critical pressure of the LNG and would normally be in the range of 4.5 to 10 MPa. Pump 120 may be sized to have a capacity slightly below the rate of delivery of LNG via pipe 100. This ensures that the liquid surface 130 remains at the top of tank 114 when pump 120 is operating. Pump 120 may be connected to control systems to regulate the speed of pump 120 in response to the position of surface 130 or in response to the internal pressure of tank 114.

When the flow in pipe 100 stops following the discharge of the LNG tanker, pump

120 may be operated for a short while until liquid surface 130 is drawn down below inlet 140 to the flare 142. When pump 120 is then stopped, valve 141 is opened and flare 142 lit.

Figure 13 shows one example arrangement of anchoring the heat exchanger pipes 98 so they have adequate flexibility to accommodate thermal expansion and contraction and to be able to resist the environmental forces, from waves and current. Fig 13 shows a perpendicular projection of an oblique view of a cut away section of the heat exchanger 90. The heat exchanger pipes 98 are deployed in horizontal spirals. For simplicity, only 3 such heat exchanger pipe 98 spirals are shown and only two partial windings are illustrated. The partial section are shown of three heat exchanger spirals 160, 161, and 162 respectively. For example in heat exchanger 160, the two partial spiral windings shown are labeled 165 and 166.

The heat exchanger pipes 98 are anchored to anchors 151 at the seabed 104. The anchors 151 are shown as heavy spheres partly embedded in the seabed 104. However, virtually, all types of anchors 151 may be used, including stake piles. The lower level 160 of pipes 98 are tied by nearly vertical chains 150 to the anchor 151. The next level 161 of pipes 98 is tied to level 160 by nearly vertical chains 154 and level 162 is tied to level 161 by nearly vertical chains 155.

For most practical cases, the pipes 98 are buoyant and would tension the chains 150, 154, and 155. However, additional buoyancy may be provided by vertical chains 156 and buoys 152. The chains 150, 154, 155, and 156 are structurally connected to the pipes 98 by collars 153. The collars 153 may provide electrical insulation between chains 150, 154, 155, and 156 and the pipes 98 to avoid galvanic corrosion by conventional designs. The chains 150, 154, 155, and 156 and collars 153 may be made from materials such as titanium, stainless steel or aluminum that can tolerate the extremely low temperature in pipe 98 without becoming brittle. Alternatively, the collars 153 may be designed to provide both thermal and electrical insulation by many possible designs between the pipes 98 and chains 150, 154, 155, and 156. Ropes from synthetic or natural materials may also be used in lieu of chain for chains 150, 154,

155, and 156.

The heat exchanger 90 is acting like an inverted pendulum supported by the anchors 151 and chains 150,154, and 155. It will therefore move when subjected to horizontal forces from current and wave action. It is important that the protective structure 92 be removed sufficiently from pipes 98 that impacts due to the motion of pipes 98 do not occur. In most ordinary cases, a distance of a few meters is sufficient. Buoys 152 and pipes 98 are placed sufficiently below the water surface 103 to prevent or hinder the buoys 152 or the pipe 98 from piercing the surface 103 even in the event of extreme wave action. If the surface 103 is pierced, one or more of the chains 156, 155, 154, and 150 may momentarily become slack and then break when tensioned in an impact following the rise of water surface 103.

Figure 14 shows a method of anchoring the pipes identical to the method employed in figure 13 except the heat exchanger pipes 98 are also restrained against excessive horizontal movement in response to hydrodynamic forces from the current and the waves. Nearly horizontal chains 170 tie the heat exchanger pipe 98 to the outer protective structure 92 and also tie each winding exemplified by windings 165 and 166 to each other. The additional restraint provided by chains 170 makes it possible for the heat exchanger 90 to resist a more energetic environment in terms of current and waves compared to the anchoring system illustrated on figure 13. Adequate flexibility to accommodate thermal contraction and expansion is provided for by mounting chains 170 with a catenary shape 171. Alternatively chains 170 may be replaced by rope, which can be made from a large range of conventional materials with adequate flexibility.

Figure 15 shows the application of vortex suppression and heat transfer fins 180 to the heat exchanger pipe in embodiments one and three of this invention. Heat exchanger pipe 98 could be vulnerable to resonance due to the hydrodynamic phenomena known as vortex shedding and strumming when subjected to a current. These phenomena require that the external cross section of pipe 98 be circular or nearly circular. These phenomena can be suppressed by equipping the pipe 98 with a strake making the cross

section asymmetrical. The strake 180 is shown deployed as a helix on pipe 98 in figure 14, however, numerous other shapes are possible. The strake 180 is shown interrupted at the collars 153 connecting to the anchoring system. The strake 180 also acts as a heat transfer fin and thereby enhances the heat transfer between the seawater and pipe 98. In most applications of the principle of enhancing the heat transfer by placing a fin on the outside of the pipe it is usually done by using a helical strake with a pitch of much less than the diameter of pipe 98. This is done to maximize the heat transfer area of fin 180. However, because ice is normally formed on the outside of pipe 98, a small pitch of strake 180 would cause the pipe to become circular when encased in ice. Therefore the pitch of strike 180 may be of an order of at least 3 diameters of pipe 98. The thickness of ice formed at the upstream end of pipe 98 normally ranges from 80 to 120 mm. Thus, the strake 180 may be at least 100 mm wide, and may have a pitch of at least 400 mm. The strake 108 may be made from the same material as the pipe 98.

Combinations of the second embodiment and either the first or third embodiments may also be made in which the offshore heat exchanger only partly heats the gas and the delivery pipe to shore also partly heats the gas. This may be supplemented with a conventional heater on shore. In this arrangement the offshore heat exchanger then does not need to be sized for the peak delivery rate. An optimal balance would ordinarily exist in which the onshore heater is only used when the seawater is cold and when the demand for gas is high. It should also be noted that the construction of the offshore heaters shown in figures 5, 7 and 8 and in figures 9 through 14 are of modular construction. If the manifolds are preconstructed with additional connections, capacity may be added to the offshore heaters by constructing additional parallel heater pipes at a later date.

In the foregoing specification, the invention has been described with reference to specific exemplary embodiments thereof. It will, however, be evident that various modifications and changes may be made thereunto without departing from the broader spirit of the invention as set forth in the appended claims. The specification and drawings are accordingly to be regarded in an illustrative rather than a restrictive sense.

WHAT IS CLAIMED IS:

1. A method of transporting liquified natural gas from a seagoing tanker to an on-shore facility, comprising:

providing a source of liquified natural gas on the tanker;

filling a riser configured to accept the liquified natural gas from the tanker with liquified natural gas;

delivering the liquified natural gas on the tanker to a sub-sea pump via the riser;

boosting the pressure of the liquified natural gas transported from the tanker to above a critical pressure of the natural gas; and

passing the liquified natural gas through a heater to achieve a near ambient temperature of the natural gas.

2. The method of transporting liquified natural gas according to claim 1, further comprising:

reducing the pressure in the riser before filling the riser with the liquified natural gas from the tanker.

3. The method of transporting liquified natural gas according to claim 1, wherein the sub-sea pump is in a cryogenic insulated pressure vessel.

4. The method of transporting liquified natural gas according to claim 1, wherein the step of passing the liquified natural gas through the heater is performed through pipes buried in the seabed.

5. The method of transporting liquified natural gas according to claim 1, wherein the step of passing the liquified natural gas through the heater is performed through pipes floating one of on and above the seabed.

6. The method of transporting liquified natural gas according to claim 1, further comprising:

passing the liquified natural gas through a heater on shore.

7. An arrangement for transporting liquified natural gas from a sea-going vessel to shore, comprising:

a sub-sea delivery pipeline configured to accept natural gas from the sea-going vessel;

a heater connected to the sub-sea delivery pipeline, the heater configured to raise a temperature of the liquified natural gas to a near ambient temperature;

a sub-sea booster pump connected to the heater by a pipe, the pump configured to accept the liquified natural gas from the vessel;

a pipeline end manifold connected to the sub-sea booster pump; and

a flexible riser connected to the pipeline end manifold configured to accept fluid from the sea-going vessel.

8. The arrangement for transporting liquified natural gas according to claim 7, wherein the manifold is configured on the sea bed.

9. The arrangement for transporting liquified natural gas according to claim 7, further comprising:

a suction pipe configured between the pipeline end manifold and the pump.

10. The arrangement for transporting liquified natural gas according to claim 9, further comprising:

a check valve in the suction pipe.

11. The arrangement for transporting liquified natural gas according to claim 7, wherein the riser is made of metal.

12. The arrangement for transporting liquified natural gas according to claim 7, further comprising:

a cryogenic insulated pressure vessel connected to the pipeline end manifold to accept liquified natural gas, wherein the sub-sea booster pump comprises a first pump which is placed in the cryogenic insulated pressure vessel, the first pump configured to pump liquified natural gas stored in the vessel to the heater.

13. The arrangement for transporting liquified natural gas according to claim 12, wherein a suction for the pump is at a low point in the cryogenic insulated pressure vessel.

14. The arrangement for transporting liquified natural gas according to claim 7, further comprising:

a second pump placed in the cryogenic insulated pressure vessel, the second pump configured with an inlet at an approximately center position of the vessel and a discharge positioned in the vessel through a discharge pipe connected to the heater.

15. The arrangement for transporting liquified natural gas according to claim 14, wherein the second pump has a lesser pumping capacity than the first pump.

16. The arrangement for transporting liquified natural gas according to claim 14, wherein the second pump is configured to pump both a liquid and vapor phase.

17. The arrangement for transporting liquified natural gas according to claim 12, wherein the vessel has check valves preventing a backflow of fluid.

18. The arrangement for transporting liquified natural gas according to claim 7, wherein pipes for the heater are immersed in the sea and supported above the seabed.

19. The arrangement for transporting liquified natural gas according to claim 18, wherein the pipes for the heater are made of one of stainless steel, INVAR, aluminum and titanium.

20. The arrangement for transporting liquified natural gas according to claim 7, wherein the heat exchanger pipe is buried below the seabed.

21. The arrangement for transporting liquified natural gas according to claim 7, wherein the heat exchanger pipe is comprised of more than one parallel pipes.

22. The arrangement for transporting liquified natural gas according to claim 7, further comprising:

a heater on-shore configured to heat the natural gas.

23. A method of transporting liquified natural gas from a seagoing tanker to an on-shore facility, comprising:

maintaining at least one pump in a temperature range so that acceptance of liquified natural gas will not damage the at least one pump;

docking a ship to a riser;

connecting an outlet for a liquified natural gas on the tanker to the riser;

providing a source of the liquified natural gas on the tanker to the riser;

delivering the liquified natural gas via the riser to a pump;

boosting the pressure of the liquified natural gas to above a critical pressure for the natural gas by the pump; and

passing the liquified natural gas through a heater immersed in the sea to heat the natural gas.

24. The method according to claim 23, wherein the pump is positioned in a cryogenic vessel.

25. The arrangement for transporting liquified natural gas according to claim 7, wherein the heat exchanger pipe is supported by submerged buoys.

26. The arrangement for transporting liquified natural gas according to claim 7, wherein the heat exchanger pipe is configured in one of a circle and spiral.

27. The arrangement for transporting liquified natural gas according to claim 7, wherein the heat exchanger pipe is configured in a helix.

28. The arrangement for transporting liquified natural gas according to claim 7, wherein the heat exchanger is a single pipe.

29. A system to transport liquified natural gas from a vessel comprising:

a riser connected to the vessel;

a manifold connected to the riser;

a pump assembly connected to the manifold; and

a heat exchanger connected to the pump assembly;

a manifold connected to the heat exchanger; and

a delivery pipeline connected to the manifold.

30. The system to transport liquified natural gas according to claim 29, wherein the manifold is connected to pipes of the heat exchanger, wherein control valves permit regulation of natural gas flow from the heat exchanger.

31. The system to transport liquified natural gas according to claim 30, wherein the manifold is connected to pipes of the heat exchanger, wherein the control valves regulate the flow in response to a temperature of the natural gas at the control valves.

32. The system to transport liquified natural gas according to claim 29, wherein the pumping assembly further comprises a tank configured to accept liquified natural gas.

33. The system to transport liquified natural gas according to claim 29, wherein the heat exchanger is configured of pipes being shaped substantially into spirals.

34. The system to transport liquified natural gas according to claim 31, wherein the heat exchanger pipes are anchored to the seabed.

35. The system to transport liquified natural gas according to claim 34, wherein the heat exchanger pipes are supported by buoys.

36. The system to transport liquified natural gas according to claim 35, wherein the buoys are connected to the pipes through chains.

37. The system according to claim 29, wherein the heat exchanger has pipes which have at least one of a vortex suppression configuration and a heat transfer configuration.

38. The system according to claim 29, wherein the heat exchanger is protected against encroaching vessels by a protective structure erected in the sea surrounding the

heat exchanger

39. A system to deliver liquified natural gas from a sea-going tanker, comprising:

a transporting arrangement for delivering the liquified natural gas from the sea-going tanker;

a cryogenically maintained pumping arrangement configured to accept liquified natural gas from the transporting arrangement and to raise the pressure to above the pressure of the receiving pipeline; and

a heat exchanger configured to take heat directly from the sea to warm the liquified natural gas.

40. The method according to claim 39, further comprising:

warming the natural gas after delivery to shore from the heat exchanger.

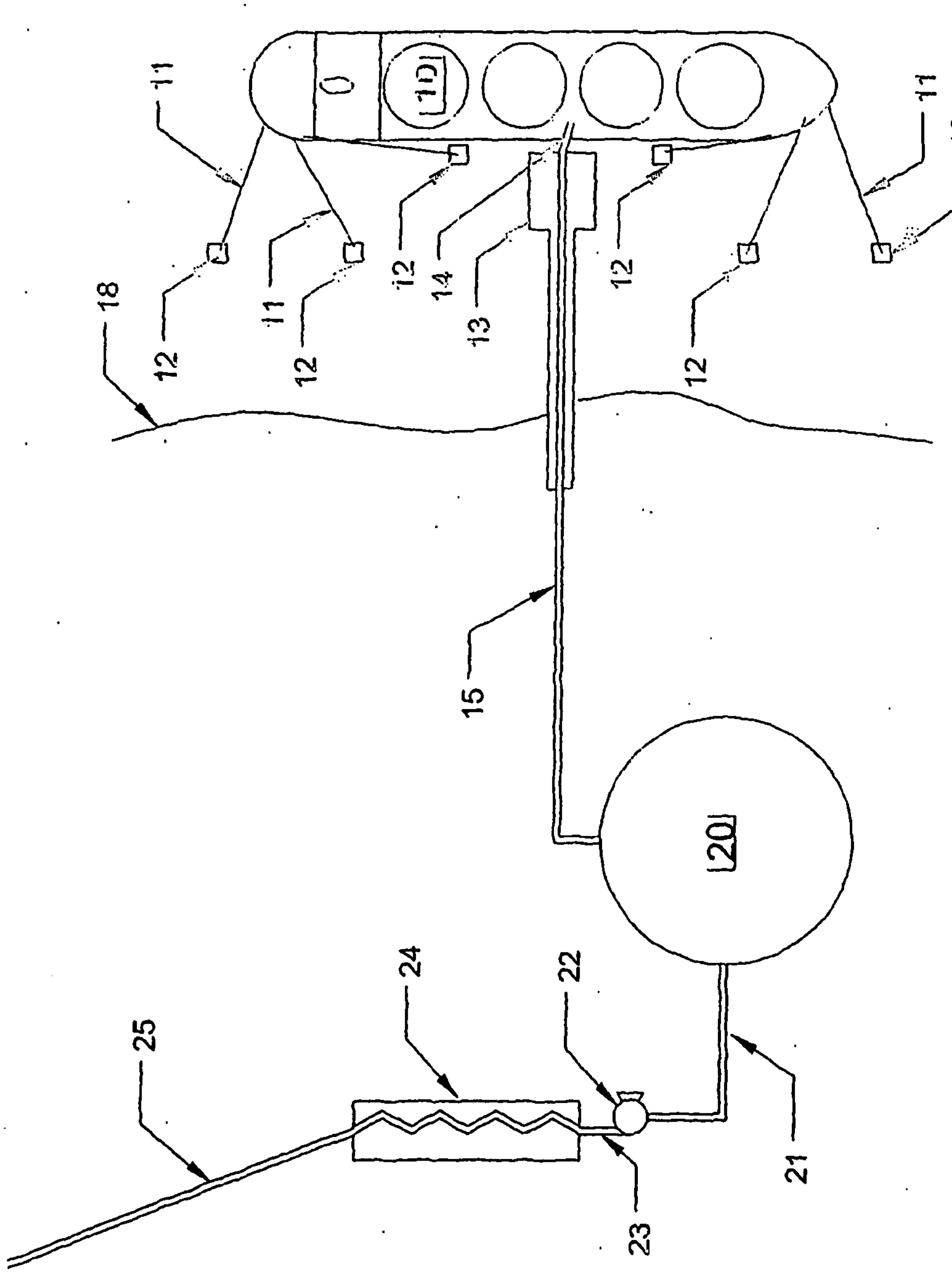


Figure 1

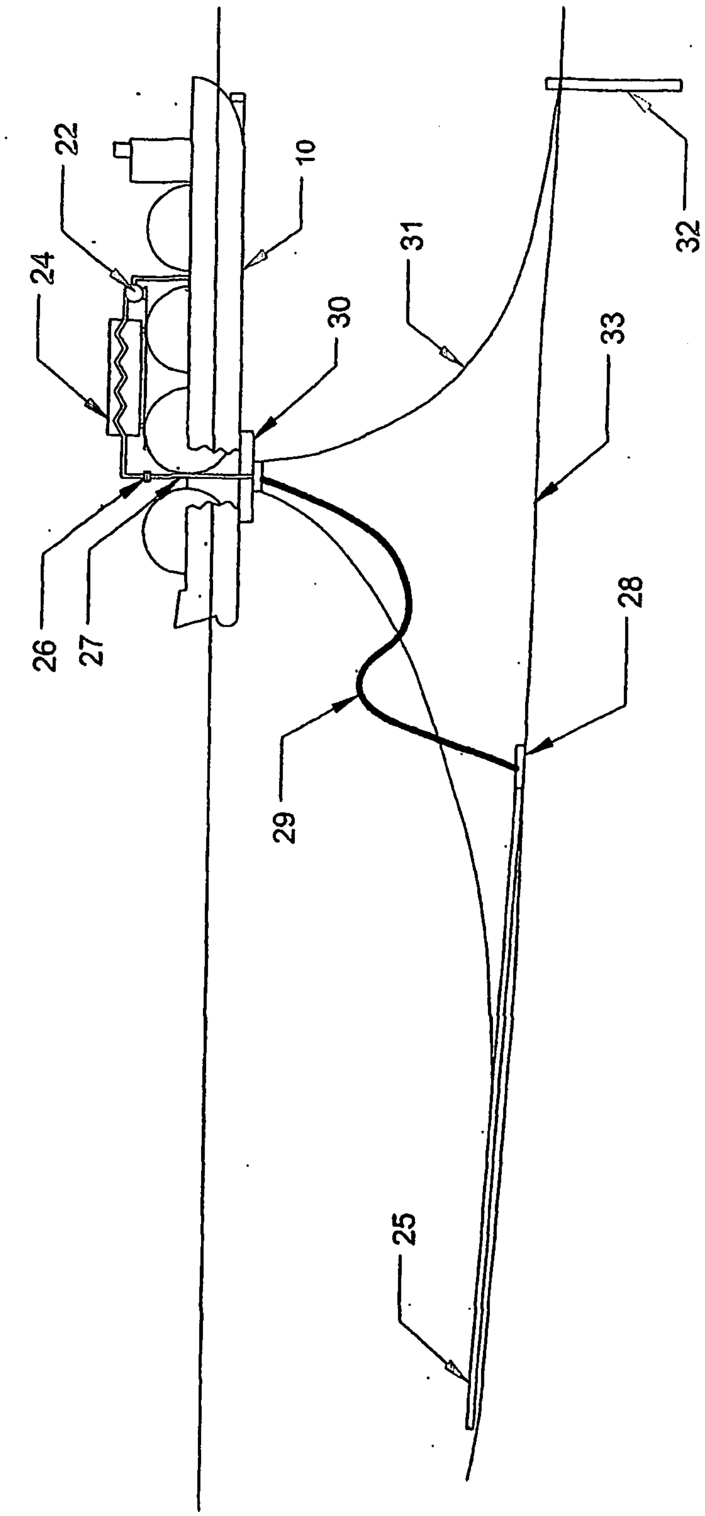


Figure 2

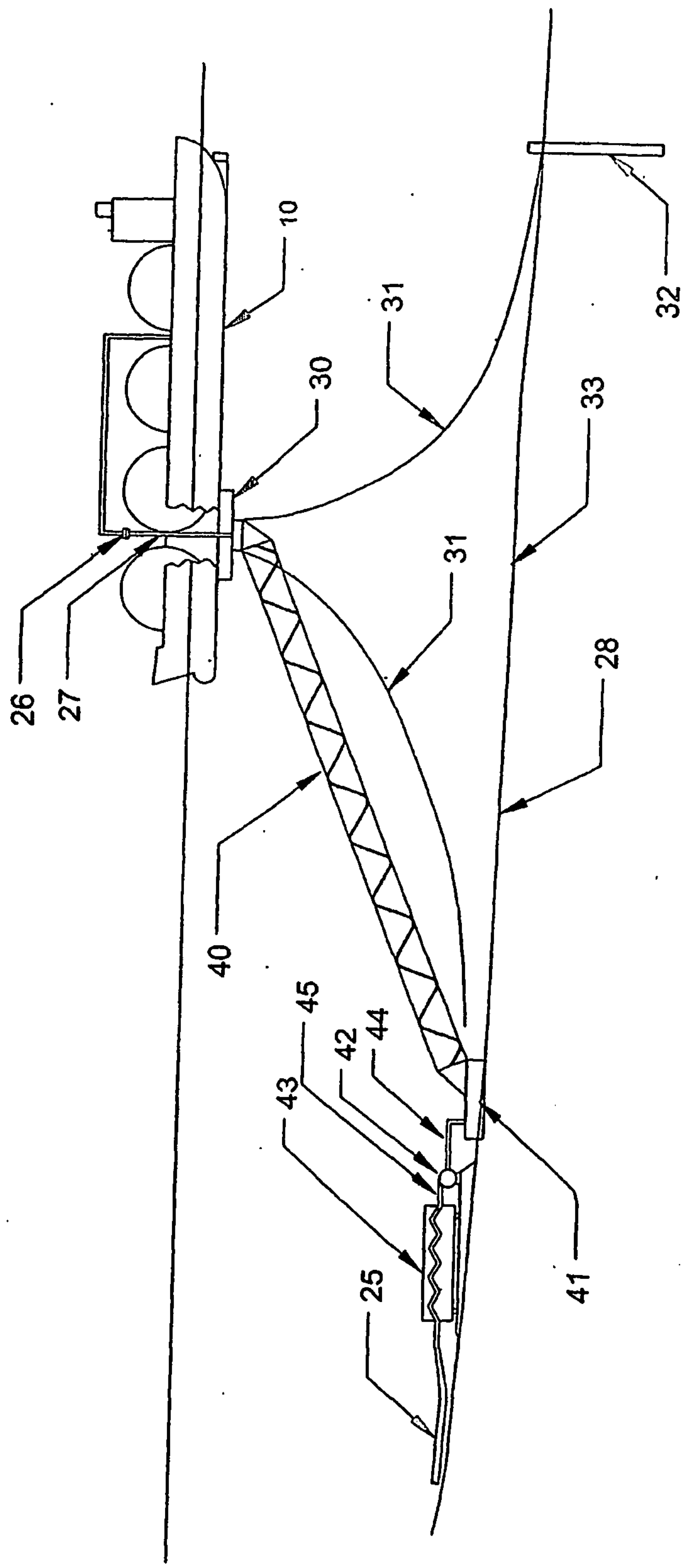


Figure 3

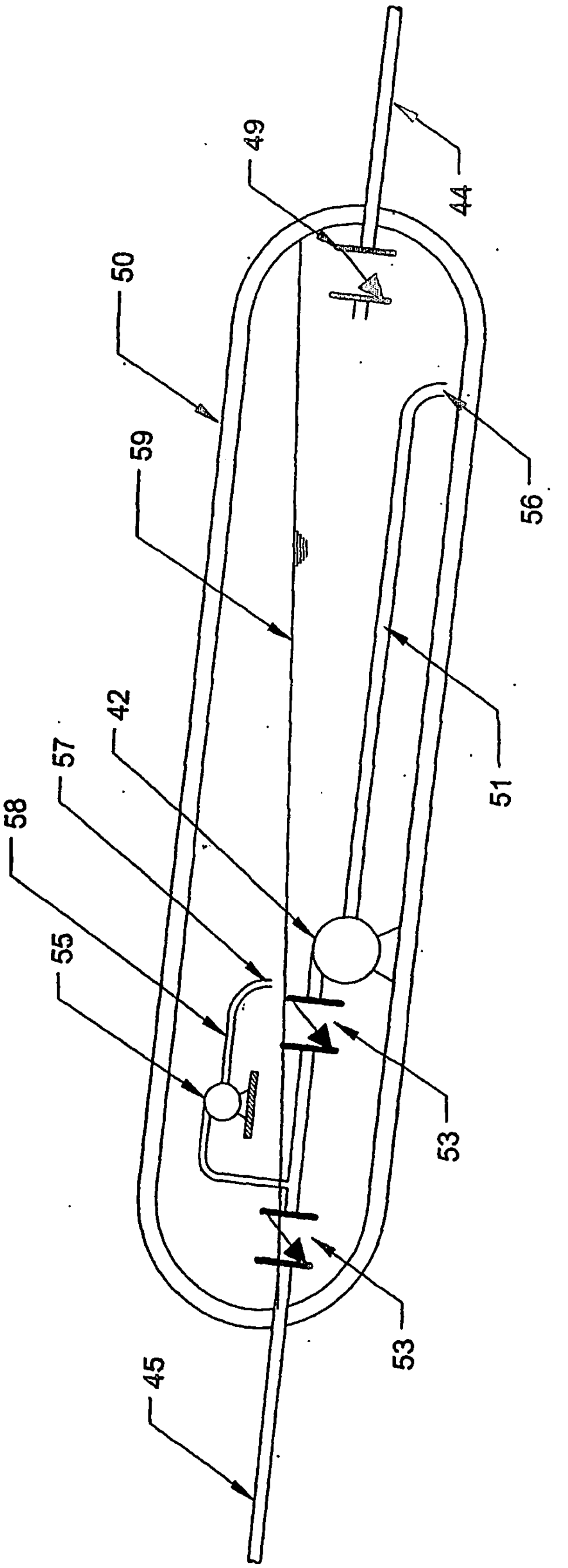


Figure 4

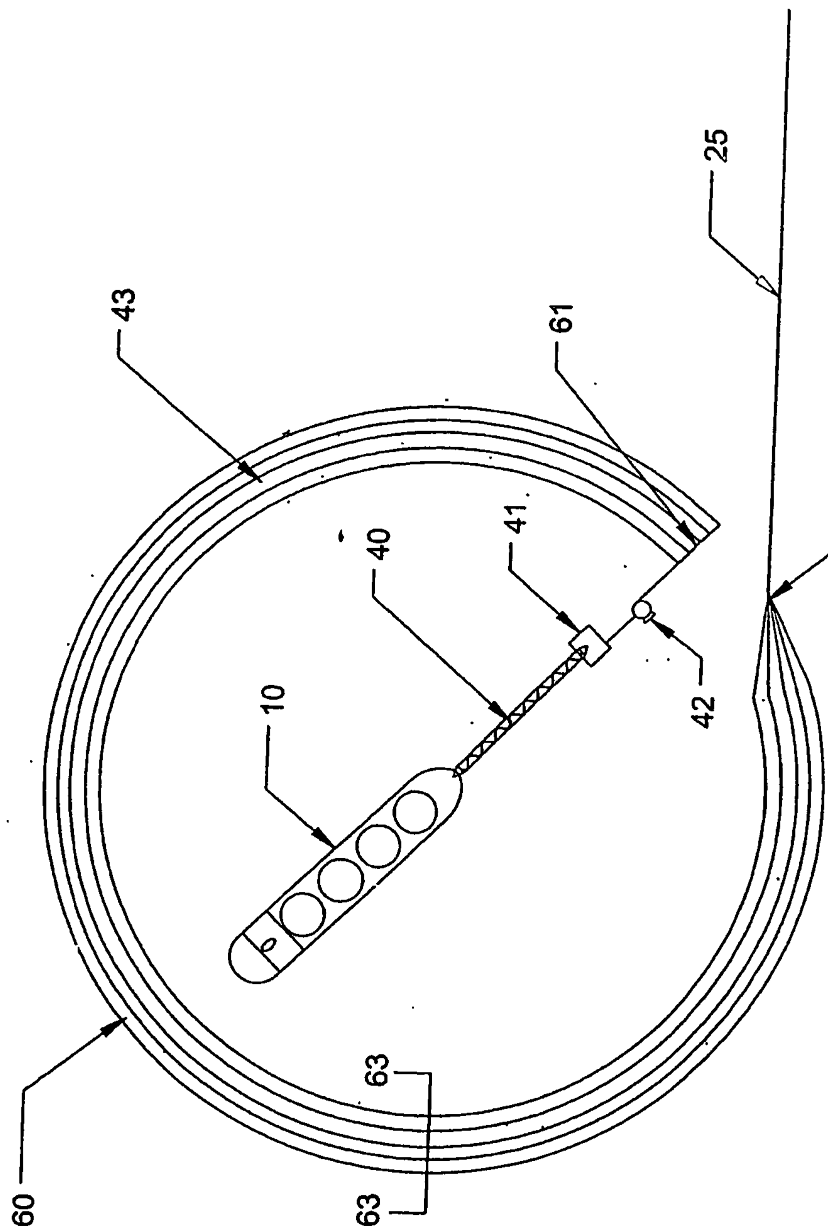
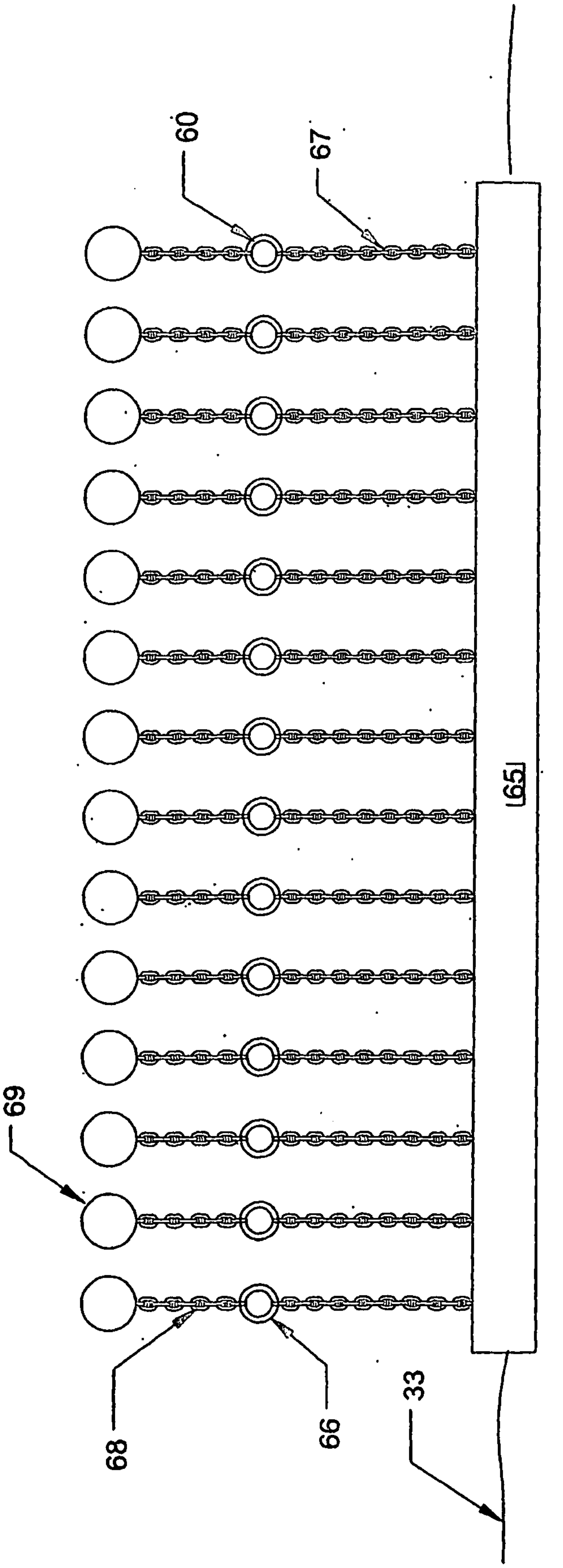


Figure 5



SECTION 63-63 (FIG 5)

Figure 6

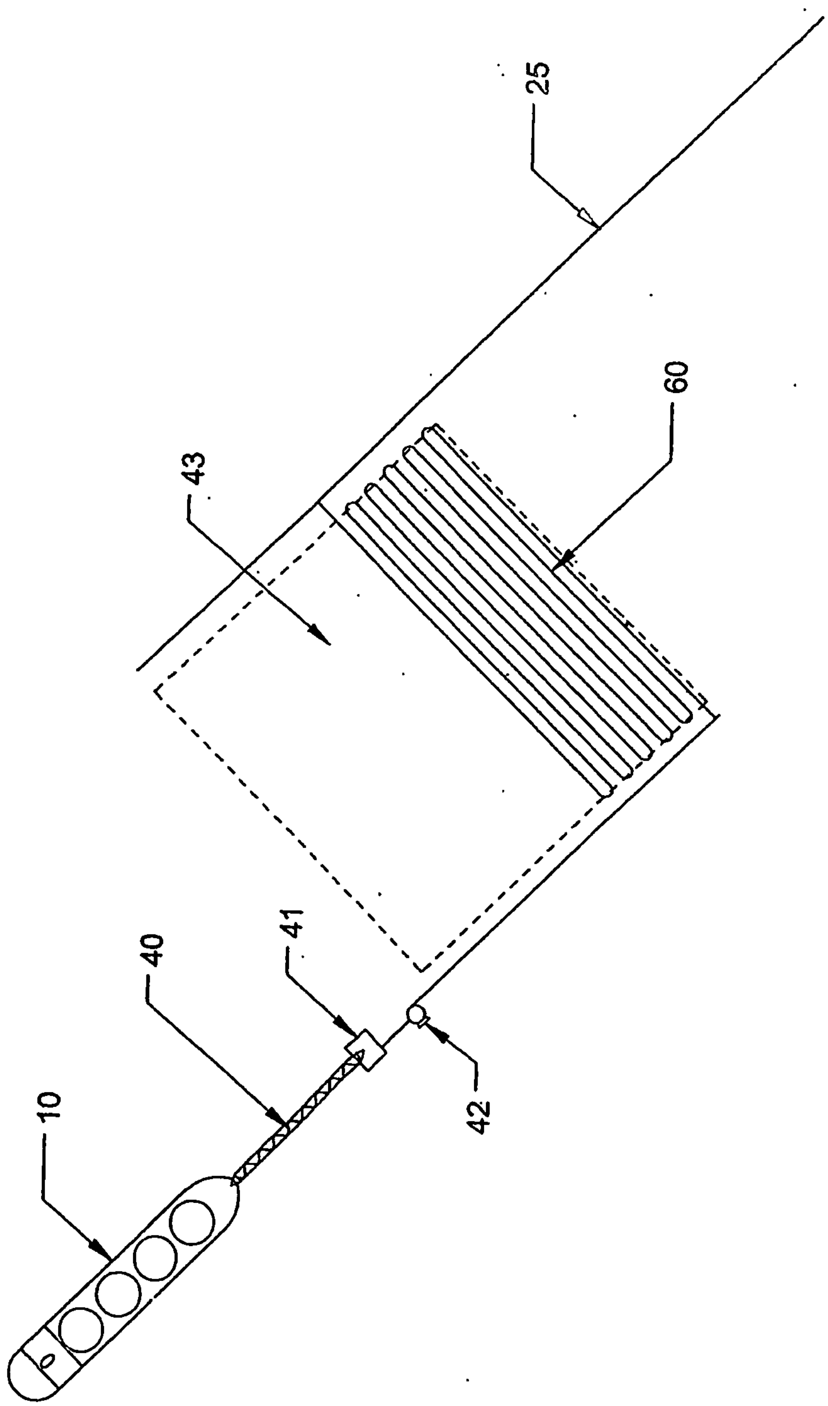


Figure 7

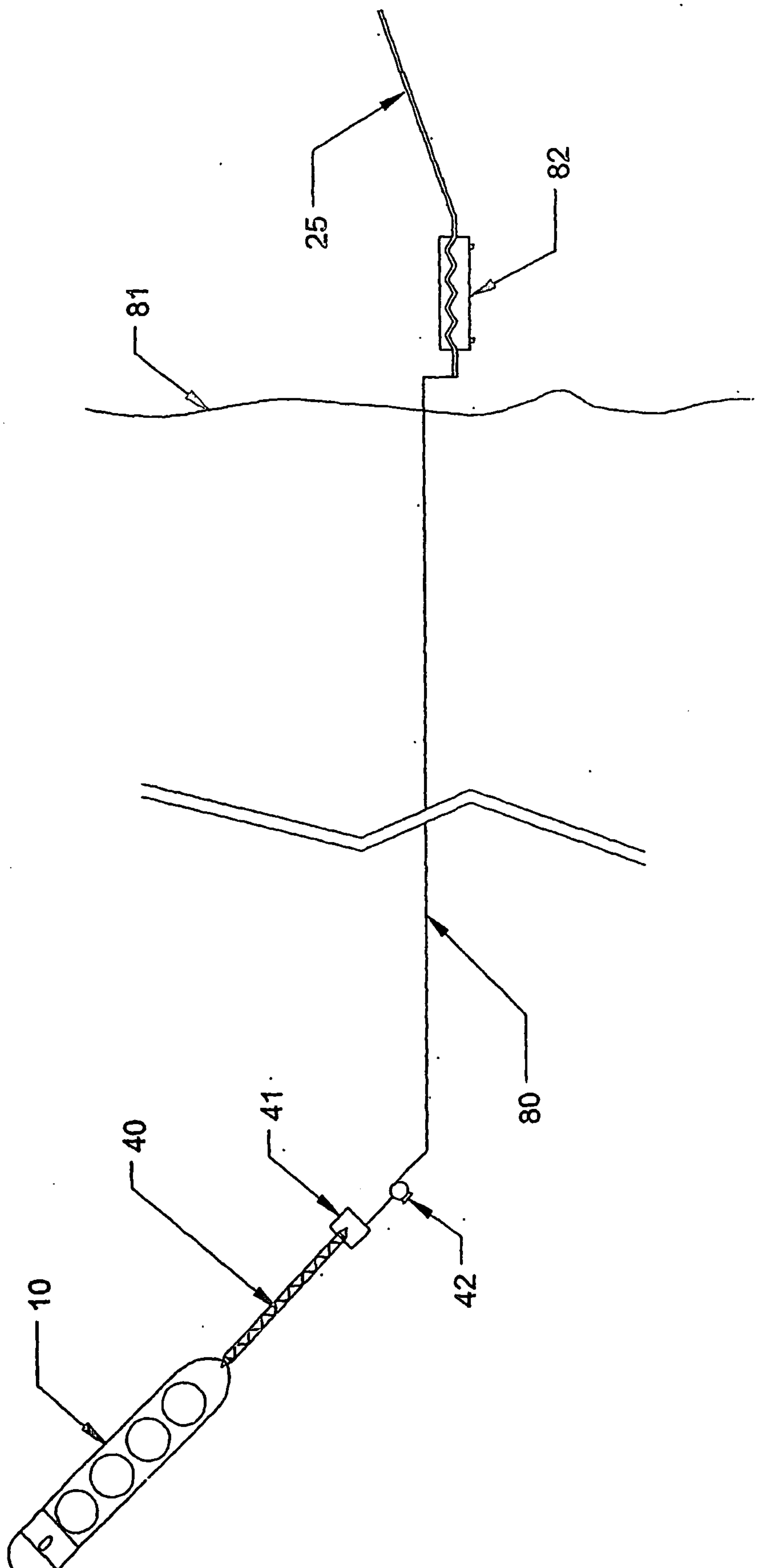


Figure 8

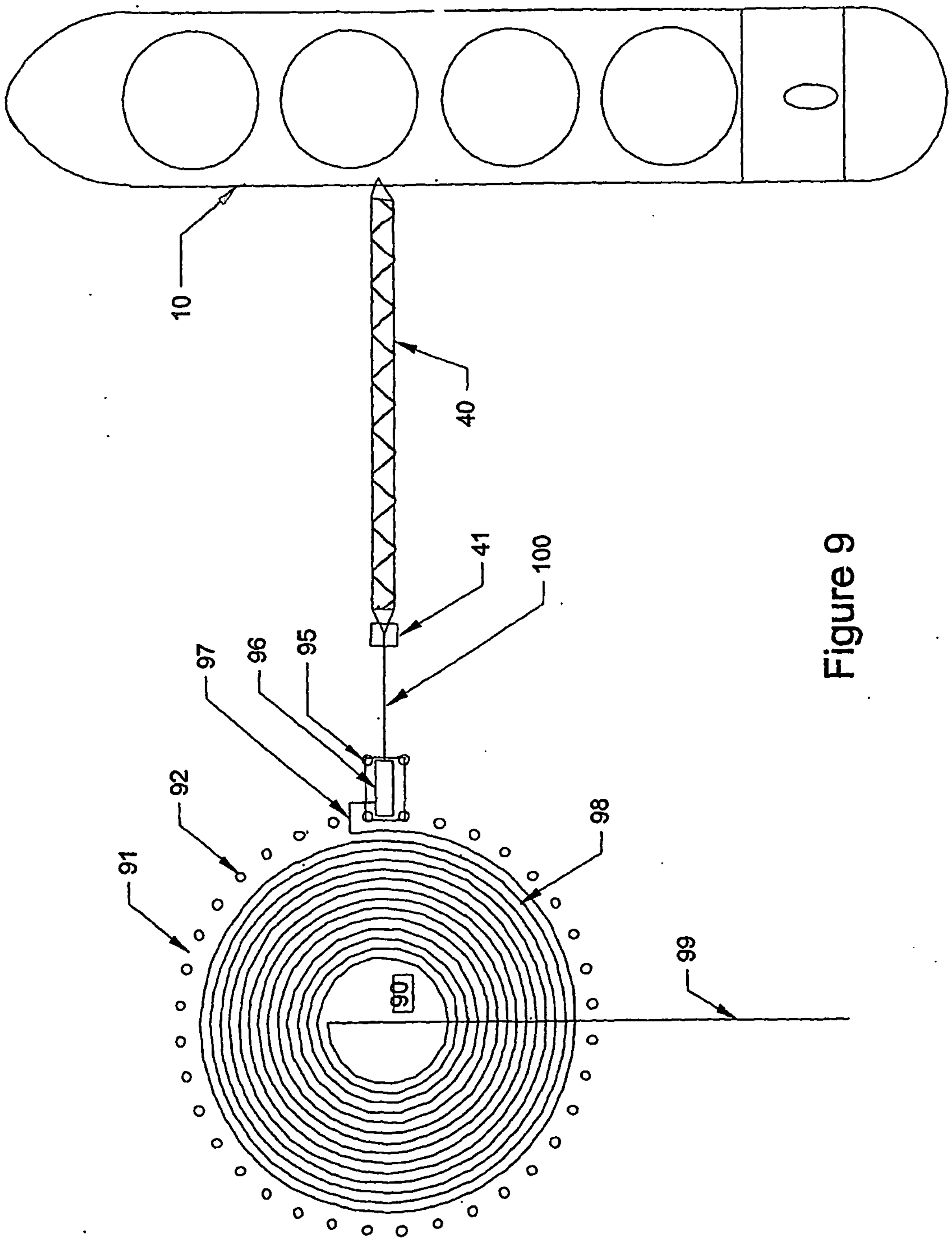


Figure 9

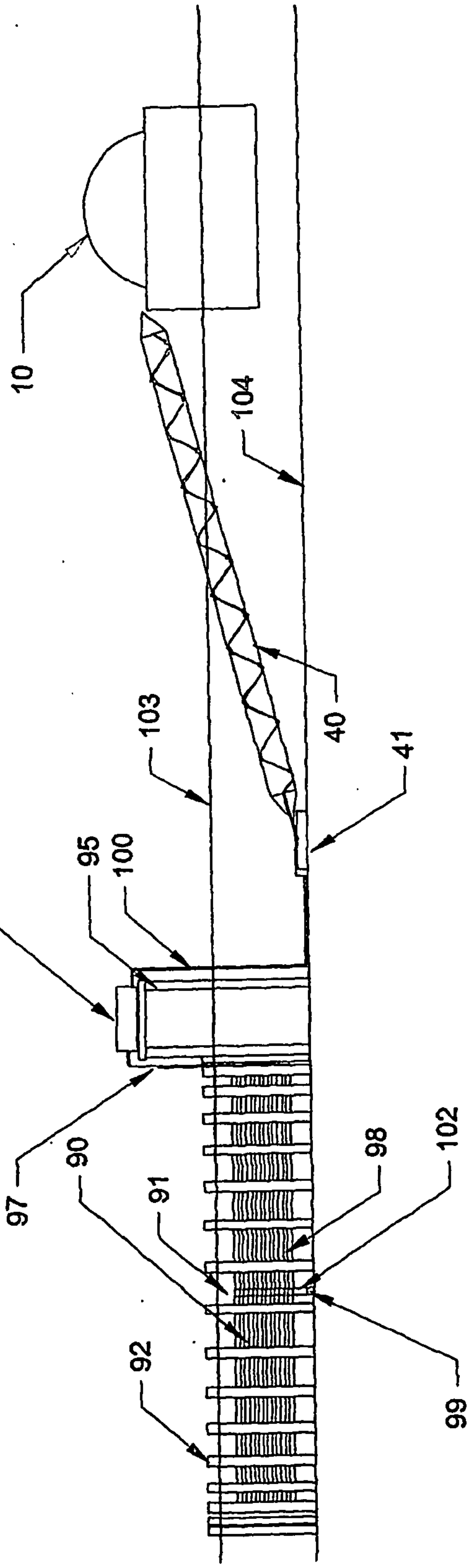


Figure 10

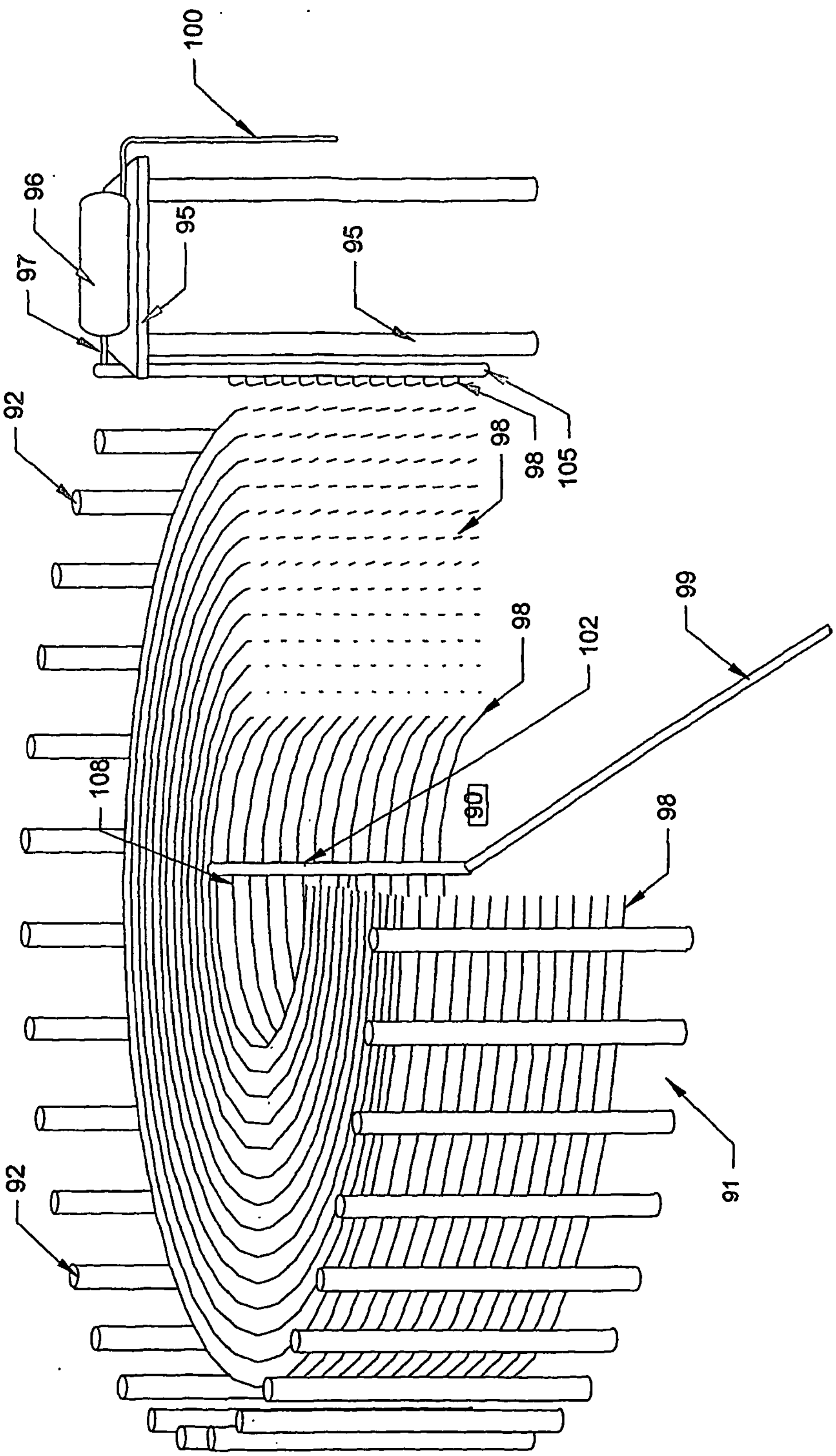


Figure 11

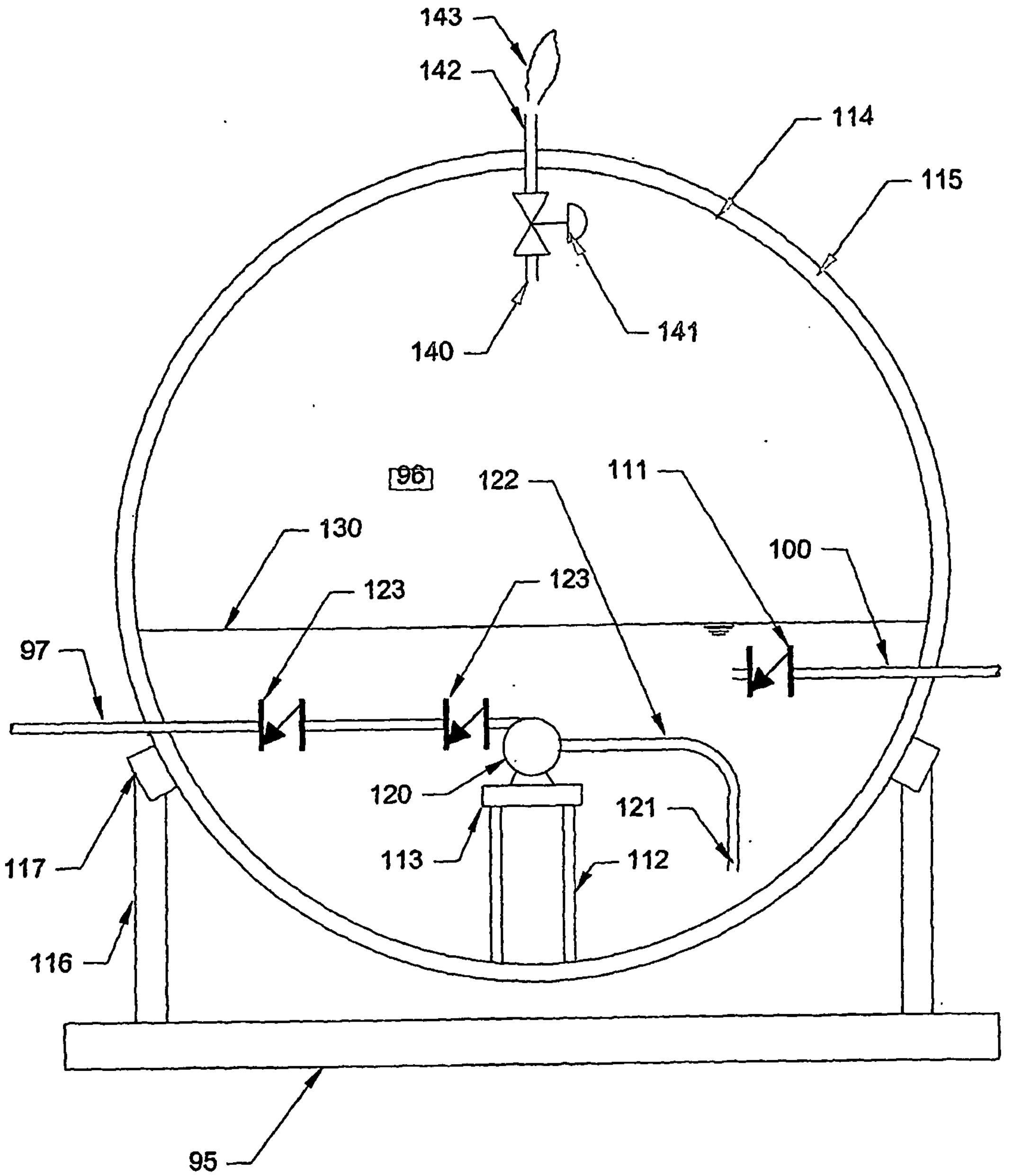

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Figure 12

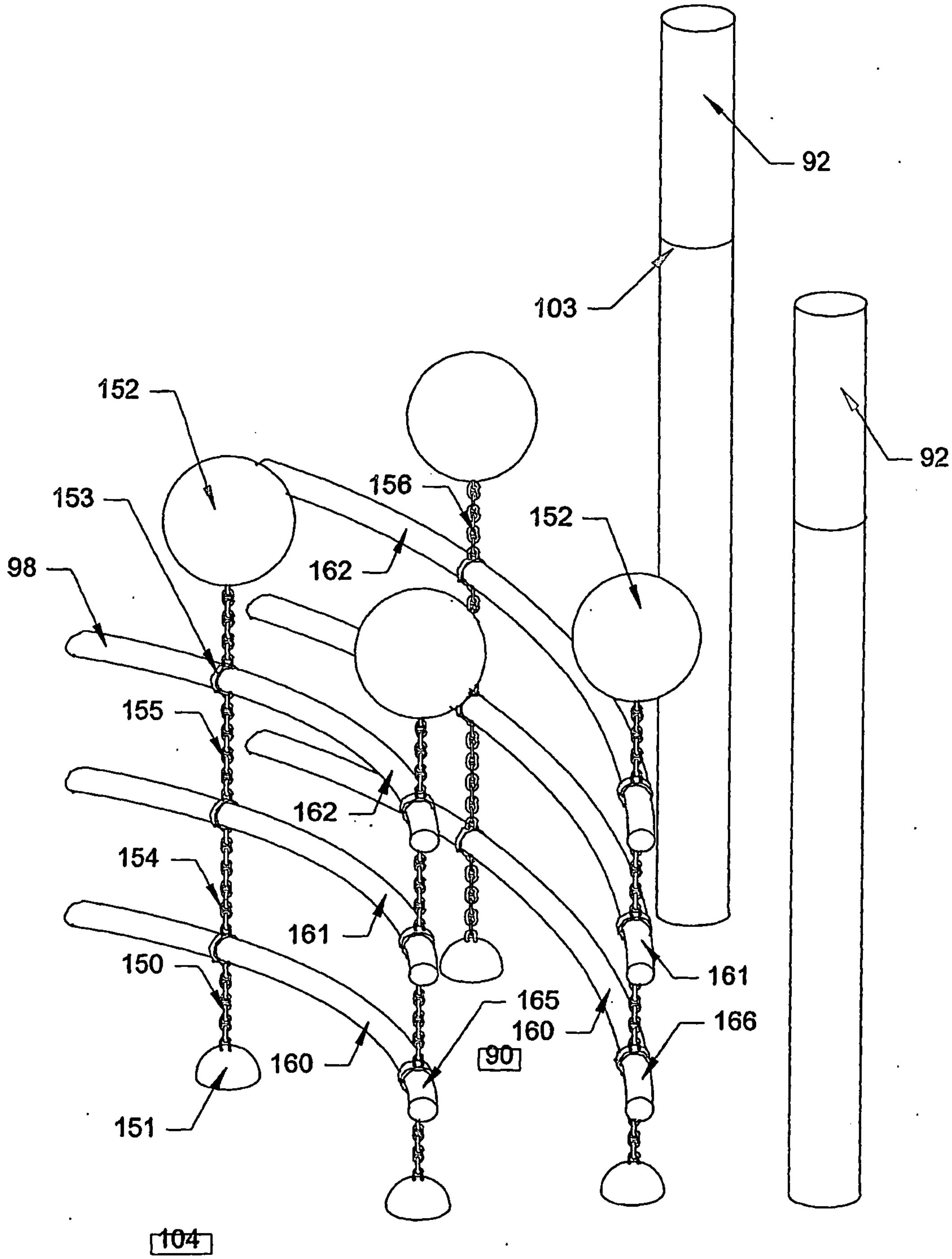
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Figure 13

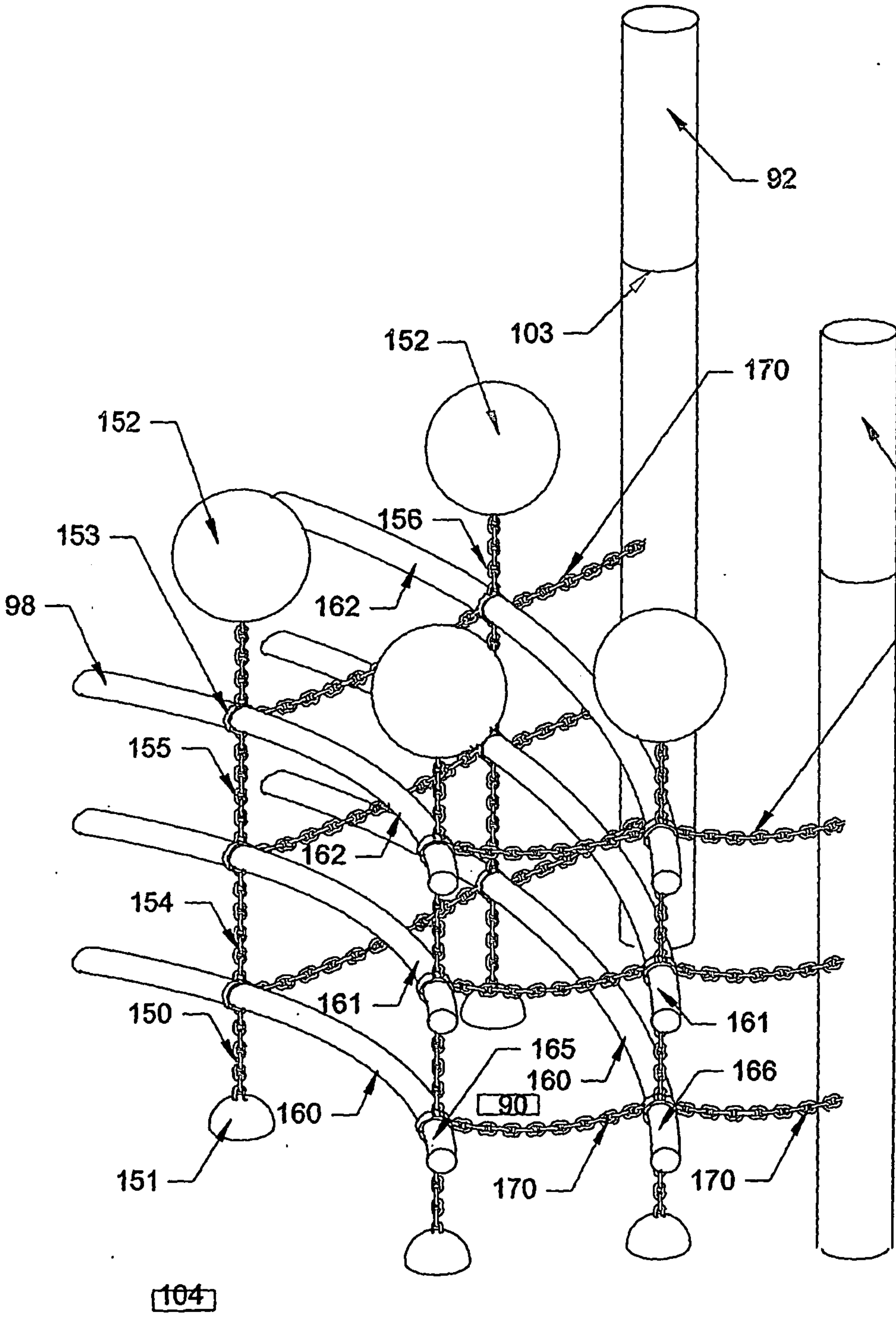
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Figure 14

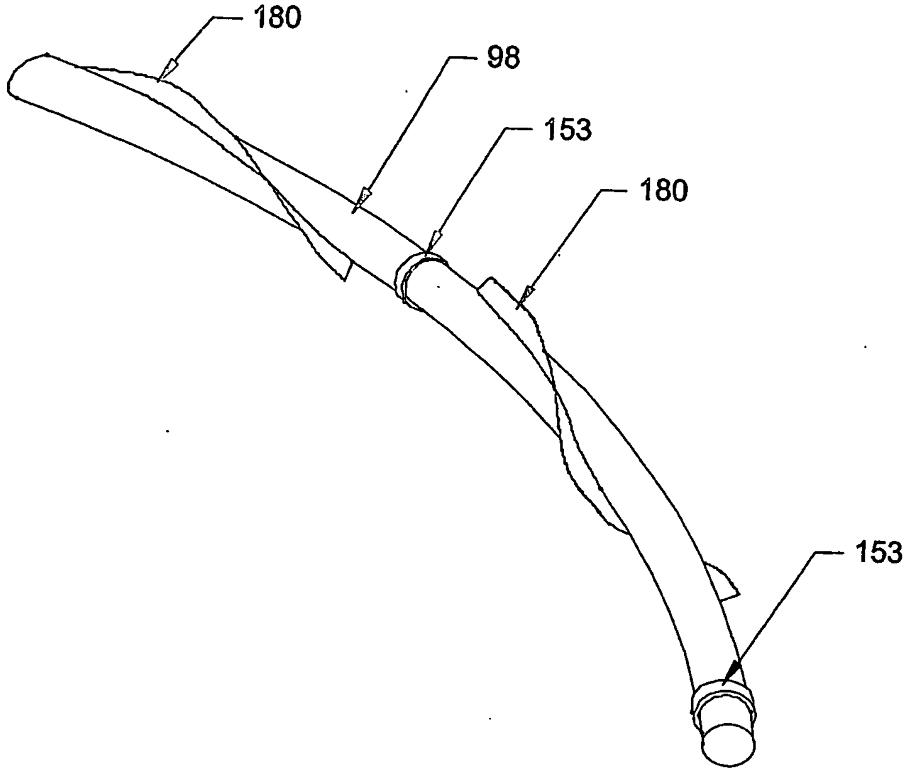

Figure 15